2020 Taskforce Report

MISO Capacity Market
With notes on NESHAP RICE:
Overview, Risks, and Recommendations

Rev. October 12, 2012
IAMU 2020 Taskforce – MISO Capacity Market

Contents

Introduction ........................................................................................................................................... 1

Executive Summary and Recommendations ......................................................................................... 2

Part 1. Basic elements of the MISO capacity market ........................................................................... 3

1. Planning Reserve Margin (PRM)........................................................................................................ 3
2. Annual Auction .................................................................................................................................. 3
3. Local Resource Zones (LRZ) ............................................................................................................. 3
   a. Zonal Resource Credits (ZRC) ......................................................................................................... 4
   b. Grandmother Agreements ............................................................................................................... 4
   c. External Resources .......................................................................................................................... 4
   d. Price Separation .............................................................................................................................. 5
   e. Fixed Resource Adequacy Plan (FRAP) .......................................................................................... 5
4. Auction Clearing Price ....................................................................................................................... 5
5. Cost of New Entry (CONE) ............................................................................................................... 5
6. Capacity Deficiency Charge ............................................................................................................. 6
7. Excess Resources .............................................................................................................................. 6
8. Behind the Meter Generation (BTMG) ............................................................................................ 6
9. Demand Response Resources (DRR) ............................................................................................... 6
10. Administrative Costs ...................................................................................................................... 7
11. Market risks (opportunities for some) ........................................................................................... 7
12. Market Price Range .......................................................................................................................... 9
13. Recommendations ........................................................................................................................... 9

Part 2. Reciprocating Internal Compression Engines (RICE) ................................................................. 12

14. RICE and the MISO Market .......................................................................................................... 12
15. RICE TIMELINE AND OTHER CONSIDERATIONS ................................................................ 12

Part 3. Other Topics on the Taskforce Agenda .................................................................................... 14

Appendix 1 – RAR Timeline ............................................................................................................... 15
Introduction

For as long as anyone reading these words has been in the electricity business, utilities have had to ensure that they had sufficient generating resources to cover their expected peak demand, plus a reserve margin for load growth and the likelihood that some generators could fail and others will be unavailable for maintenance and repairs. Before MISO, the Midcontinent Area Power Pool established the reserve margin. The new Resource Adequacy Requirement (RAR) construct is just another twist in the story of how to ensure that enough resources are available. Like so many of the industry’s policy developments it attempts to use market forces to replace regulation and, as usual, that means a lot more of a different kind of regulation.

So, just what is the RAR and why do we care about it? The MISO capacity market actually began in 2009. However, there will be significant changes starting June 1, 2013. The objectives of this new market are to provide price signals that encourage new construction, simplify delivery within defined zones, manage reserve margins, and enable demand response to compete with generation.

A detailed, working knowledge of the market’s operation and the new obligations it imposes on utilities may not be so important for most IAMU members. After all, most are members of a joint action agency (JAA) or are wholesale customers of another utility that will likely take care of those details. Some of those detailed obligations are coming up. For example, by November 1, 2012 your MISO peak coincident demand forecast must be filed, using approved methods (trend models are no longer acceptable). If your utility or power supplier is not planning to participate in the forward capacity market, a Fixed Resource Adequacy Plan must be filed by the 7th business day in March. These and other obligations can be found in Appendix 1, the Resource Adequacy Timeline. Look especially at items where the Load Serving Entity (LSE), Resource Owner, or in some cases Load Modifying Resource (LMR) Owner are listed as the responsible entity. If there is any doubt at all that your obligations are being met, check with your JAA or other power supplier to be sure the tasks are being handled.

In this preliminary report the 2020 Taskforce attempts to explain the basic elements of the new market, describe some of the price risks associated with the market, and identify no-risk and low-risk strategies for mitigating these risks.
Executive Summary and Recommendations

MISO is changing the way utilities conduct planning to ensure there are sufficient resources to meet demand through its Resource Adequacy Requirements (RAR). For the year that begins June 1, 2013, resources needed to meet annual forecast coincident peak demand, plus reserves, will be subject to a reverse auction. Resources are bid into the auction by market participants and the offer price of the last unit needed to satisfy resource requirements becomes the price paid to all resources that clear the auction. Since only a few Iowa municipal utilities are market participants, MISO’s Resource Adequacy Requirements (RAR) are likely to be an obligation of the utility’s joint action agency (JAA) or other power supplier. This overview is intended to provide sufficient information so that utility managers and policymakers have a basic understanding of how the market works, what risks and opportunities it presents, and what questions to ask of the market participant acting on behalf of the utility.

Actions to meet the timeline for the June 1, 2013 auction have already begun. For example, by October 31, 2012, resource owners must provide verification of their generators’ capacity and availability. By November 1, 2012 forecasts of coincident peak demand and required resources must be submitted. By those dates, a utility ought to be able to learn from its power supplier its share of the forecast coincident peak and whether its local generation or demand response resources are required to meet the total participant’s resource obligation. (See Appendix 1 for a detailed RAR timeline)

Many IAMU members operate diesel electric generators, which are subject to EPA’s NESHAP RICE rule. Questions about whether to retrofit non-compliant engines and how those resources fit into the market are significant. To some extent, the answers cannot be known until the EPA makes a final decision on proposed amendments to the rule. That decision may not be known until December 23, 2012. If the proposed amendments are adopted, existing engines can be used without modification to fulfill current market requirements. (See Part 2, §§ 13 & 14)

Utilities ought to have at least a general understanding of risks and opportunities presented by the new capacity market. (See Part 1, section 10) An interesting feature of the MISO RAR is that demand response resources (DRR), such as air conditioner load management programs and some energy efficiency programs can compete in the auction on the same terms as generation. In other words, the ability to avoid a kW of peak demand has the same market value as a diesel generator or gas turbine. (See Part 1, § 8) Above all, utilities should consider all cost effective measures to reduce risks or capture opportunities. For many utilities this means re-thinking rates, policies, and infrastructure investments. Business as usual is not likely to provide a winning strategy. (See Recommendations, Part 1 § 12)
Part 1. Basic elements of the MISO capacity market

1. Planning Reserve Margin (PRM)

MISO calculates the planning reserve margin, based on load forecasts, estimates of forced outages (plant failures), and planned outages. The planning reserve margin (PRM) is the percentage of total forecast coincident peak beyond that needed to supply the region’s peak demand. The PRM could vary by zone.

2. Annual Auction

There will be an annual auction for each zone, which will account for ALL loads and ALL resources in the zone. The auction opens during the last three business days in March. Auction results are posted on the 5th business day in April.

3. Local Resource Zones (LRZ)

MISO has established zones that are deemed to have adequate capacity availability (see figure 1). State boundaries were initially targeted as guidelines for the zones, but boundaries were adjusted so as to not split any local balancing areas. Iowa is Zone 3, which was adjusted to include all of Alliant’s balancing area including a thin slice of southern Minnesota. There are a number of criteria that MISO uses to set the zonal boundaries.
Deliverability is guaranteed within the zone, but transfers into or out of the zone may be limited. Based on MISO’s preliminary analysis, zone 3 does not have a capacity import limit. There is a temporary (2-year) grandmother provisions allowing some out-of-zone resources are treated as though they are in the zone, e.g., WAPA.

a. **Zonal Resource Credits (ZRC)**

A ZRC is a credit for owning resources that count towards MISO resource adequacy requirements. By selling ZRCs from capacity, an entity does not give up any transmission, ARR, or energy production rights, other than being required to meet the MISO Must-Offer requirement. ZRCs replace PRCs (Planning Resource Credits), which are part of the existing construct, and will be granted to resource owners in the same way that PRCs are currently granted. Under the current construct, resource credits (PRCs) can be applied anywhere in the footprint. Under the new construct, resource credits (ZRCs) are zone specific.

It is important to note that ZRCs are available in 1/10 MW fractions. For a small utility, crossing the threshold into a new 100 kW fraction of coincident could be expensive, as the load is rounded up. If the forecasted coincident peak load is 2.102 or 2 kW more than a 100 kW fractional ZRC, the utility will pay for 98 kW it does not need. That could easily be $8,000 to $10,000. Presumably the load serving entity (JAA or other market participant) will aggregate the demand for its members or customers, but for utilities whose power supplier passes along all market costs, it would be worthwhile clarifying whether the wholesale bill will be based on full 1/10 MW fractions.

b. **Grandmother Agreements**

In its conditional approval of MISO’s RAR proposal, the FERC made several changes. One, which is important to some IAMU members is the two-year limit it placed on utilizing Grand Mother Agreements (GMA), so they cannot be used any later than May 31, 2015 (cannot be used for 2016 or even the summer of 2015). GMA contracts are financial hedges that allow the holders to avoid the differences in zonal resource capacity (ZRC) prices. Also note that registered external resources (including the WAPA purchases) that sink in Iowa will receive Zone 3 ZRCs; since they are in the same zone, there is no need for a GMA hedge.

IAMU members relying on resources located outside zone 3 will need to confirm with their power suppliers whether those resources will receive zone 3 SRCs beyond the expiration of the grand mothering provision. Again, despite earlier estimates of very tight import limits for Zone 3, MISO’s current projections do not indicate a significant limit.

c. **External Resources**

If a load-serving entity in zone 3 uses a resource that is external to MISO, e.g., WAPA, Laramie River, or generation in Nebraska, the registered resource will receive zone 3 ZRCs. If the resource is in another MISO zone, ZRCs for that resource are interchangeable with zone 3 ZRCs, while a two-year grand mothering provision is in place. That provision expires
at the March 31, 2015, so there is the potential for price separation between the ZRCs for different zones (see “d” below). Each entity will likely be impacted differently depending on where their load and generation is located, so a utility that depends on generation located outside Iowa should check with their power supplier about this risk.

d. **Price Separation**

External resources used to serve Iowa load, which do not receive zone 3 ZRCs get ZRCs for the zone in which the capacity is located. Selling those external ZRCs and buying ZRCs in an import-constrained zone like Iowa could result in price separation in which a premium is paid for ZRCs in the import-constrained zone. Of course, the converse could also be true. If zone 3 ZCRs have a higher value because of import limits, an entity with resources in zone 3 could sell unneeded ZRCs and purchase lower priced ZRCs to serve load in another zone.

e. **Fixed Resource Adequacy Plan (FRAP)**

There will be an annual auction for each zone, which will account for ALL loads and ALL resources in the zone. Participation in the auction is not mandatory. In lieu of participation, a load serving entity may submit a Fixed Resource Adequacy Plan (FRAP) that matches its forecast load and reserve requirement with its own resources or PPAs, so that the load is not subjected to the auction clearing price. Resources used for a FRAP are not eligible for any auction clearing revenue. In practice, MISO will offer any FRAP resources in the auction at a zero dollar offer price. The submitting entity will receive Zonal Resource Credits (ZRC) for is qualifying resources.

The deadline for filing a FRAP for the planning year beginning June 1, 2013 is March 11, 2013. As noted above, other requirements can be found in the MISO Adequacy Resource Timeline (Appendix 1).

4. **Auction Clearing Price**

Resources can be offered in the auction at any price, but only those that clear the market will be paid. All resources necessary to meet the total coincident peak, plus reserves, for the zone have “cleared the market” and receive the offer price of the last resource needed. This is the market clearing price.

5. **Cost of New Entry (CONE)**

The maximum price is equal to the cost of adding new generation, referred to as the Cost of New Entry. For the June 1, 2013 year, MISO has proposed CONE value of $97,650 per MW-year ($8.17 per kW-month) for Resource Zone 3 (Iowa), subject to FERC approval. These values could vary resource zone, but are not likely to do so in the first year. If there were insufficient resources to meet the coincident peak demand plus reserves, load serving entities needing additional capacity would pay the CONE value for needed resources. [It is not clear to IAMU how this would work in a one-year look-ahead market. The auction in PJM is a three-
year look-ahead, so deficiencies could be met at CONE using short lead-time resources, like simple-cycle gas turbines or demand response.]

6. Capacity Deficiency Charge

A utility that does not have enough resources to meet its forecast coincident peak demand, including its own resources, what it rents in a power purchase agreement, or what it gets from the auction, is subject to a Capacity Deficiency Charge. Although this situation should not occur, it is worth noting that for the planning year beginning June 1, 2013, the Capacity Deficiency Charge is 2.748 times the CONE. (2.748 x $97,650 = $268,342.20 per MW-year, assuming FERC approves the MISO proposal).

Note that a deficiency is based on forecast demand. The reserve margin takes into account the likelihood of summer heat anomalies, so there not much of an excuse for a utility being subject to the deficiency charge. MISO will carefully scrutinize forecasts, which must be prepared using new analytical, econometric methods. A forecast based on load trends is not adequate.

7. Excess Resources

Excess resources (unless behind the meter) must be offered up in the auction. However, a market participant can withhold up to 50 MW of generating capacity, subject to review by the market monitor, whose role is to prevent the exercise of market power. Resources that clear the auction will receive the market clearing price, even if the offer price is zero. Only “market participants” can participate in the auction. With few exceptions among IAMU member, this would be the JAA or power supplier or possibly a third party acting on behalf of the utility or JAA.

8. Behind the Meter Generation (BTMG)

Behind the meter generation, (e.g., most Iowa municipal utility diesel electric generators, except RPGI’s) can be offered in the auction and receive the market clearing price or can be used to satisfy the requirements of a fixed resource adequacy plan. BTMG is also referred to as a load modifying resource (LMR). LMRs must be available and respond during an emergency. They have up to 12 hours to respond. They must be able to run during the first 5 summer deployments for which they are called and must be able to run for a minimum of 4 hours (up to 20 total hours per year). Generator Verification Test Capacity must be demonstrated by October 31 for the planning year. Existing resources must renew registration by February 1. New resources or those with increased capability must demonstrate capability by March 1 for the planning year.

9. Demand Response Resources (DRR)

All Demand Response Resources (DRR) used to net against a load serving entity’s forecasted coincident peak demand or load modifying resources that are cleared in the auction must be
available for use in a capacity emergency, as declared by the transmission provider, pursuant to the transmission provider’s operating procedures. Demand response can be offered into the market and receive the market clearing price and ZRCs. DRRs have the same availability and limitations as behind the meter generation. They must be able to run for a minimum of 4 hours (up to 20 total hours per year). By October 31, existing DR resources must demonstrate demand reduction capability for the planning year. Their registration must be renewed by February 1. New resources or those with increased capability must demonstrate capability by March 1 for the planning year.

10. **Administrative Costs**

The planning reserve market has been operating on a monthly basis since 2009. While the Annual RAR introduces complexities, it also will only occur once per year instead of monthly. There is no apparent reason to expect significantly higher administrative costs.

11. **Market risks (opportunities for some)**

Besides at least a basic understanding of how the market will operate and the timeline for the annual auction, IAMU members should have a sense of the risks attendant to the market, especially those that could impact capacity price. Knowledge of these risks might influence the decision to retrofit or replace an existing diesel engine; whether it makes sense to join other utilities in investing in new generation or transmission; when to install smart meters and how you will use them; how energy efficiency and other demand response programs should be integrated into your utility’s or JAA’s resource planning; and, what changes should be considered in future rate design. Here are some of those risks, with a brief explanation of how each might impact price:

For a number of reasons, MISO currently has significant capacity reserves: (1) current participants have a lot of generation; (2) the economic down-turn has reduced demand; (3) demand growth has been reduced by efficiency; and, (4) many older plants have remained in service because owners aren’t sure how and when to replace them. Uncertainty stems from the absence of a clear energy policy and future regulation, changes in market structure, unknown fuel prices, and the potential for dramatic changes in technology. However, enough is known about the near future that MISO has projected a capacity shortfall by as early as 2016.

Among reasons that the region could go from excess to shortfall in such a short time are that many older coal-fueled plants are being retired due to their age and/or the cost of retrofits that would be needed to comply with emission limits imposed by EPA’s MATS rules. These rules go into effect in April 16, 2015 (plus possibility of two one-year extensions) and many surviving coal-fueled generators will undergo retrofitting with scrubbers, bag houses, or other pollution control technologies that will result in months of planned outages. The compliance date for the small boiler MACT rules is March 2015. There are many other variables that could impact the cost of generating capacity in MISO, including these:
• Though natural gas prices are currently quite low, price volatility is expected to return. If natural gas becomes the primary fuel for new electric generation that would also put upward pressure on gas prices.

• The pace and extent of economic recovery will influence growth in electrical demand. The faster and steeper the recovery trajectory, the sooner the region goes deficit and the higher the price of capacity.

• Climate/weather related record summer heat could increase need for capacity and reserves. Peak demands generally occur when there are consecutive days of record temperatures with relatively high night-time temperatures. Those are precisely the kinds of broad regional events seen in the summer of 2012.

• River levels in periods of drought could fall below the cooling water intake structures of some power plants. Extended periods of hot weather can also raise river temperatures, which could limit the output of some plants that rely on that water for cooling purposes. Loss of that capacity could be devastating during peak events.

• Commodity prices for new plant construction (both domestic and foreign) are rising, especially as China and India build new plants to fuel their rapidly growing economies.

• Unlike PJM, most of the MISO states do not have retail competition. Consequently, there has been little growth of third-party demand-response (DR) aggregation. The FERC has allowed municipal utilities to block third party aggregation in their service territories (municipal utility governing bodies must affirmatively act to allow third parties to operate locally). The IUB has blocked third party aggregation in service areas of rate-regulated utilities. While municipal utilities generally favor the exclusion, it should be noted that much of the need for new capacity in PJM has been met by DR. Short lead-time generation (CTs) and DR has supplied about 93 percent of new capacity in PJM. In the absence of third party aggregators, demand response could be slow to develop as a resource, thus adding upward pressure to auction prices.

• There is potential for large players with strategically-located assets to exercise market power. MISO has a market monitor whose purpose is to prevent this from occurring, but it is a potential risk worth acknowledging.

• MISO and PJM appear to be moving toward greater cooperation. Capacity prices in PJM are much higher than what is expected to be the case in the new MISO market. To the extent that the markets merge, there could be upward pressure on price.

• Iowa utilities may find it difficult to site new gas-fueled generation, because pipeline capacity is limited. This could delay the response to the need for new capacity and could also make it difficult to relieve congestion.

• High gasoline prices could accelerate consumer acceptance of alternate fueled vehicles, increasing demand for electricity and/or natural gas. A switch to either fuel would add
pressure on capacity prices. Electrification of transportation, especially in the absence of time-of-use pricing could dramatically increase the need for new resources.

- Though near-term risk of a state or federal renewable portfolio standard is unlikely, there are portfolio standards in some of the other MISO states and the mounting evidence of climate change may eventually force policies that address the problem. Whether tax credits are extended for renewable resources will also impact capacity prices.

12. **Market Price Range**

The Taskforce has no crystal ball that reveals the future price of capacity. The top end of the range is at least known for the 2013 planning year. It is the cost of new entry, which MISO has set at $97,650 per MW-year for Zone 3. Whether or by how much the CONE increases in following years depends on the various risk factors, such as those noted above, play out. The low end of the cost range is harder to predict, though the consensus among taskforce members is that the MISO market will be well below the CONE in the first year. As MISO approaches a capacity deficit, it is reasonable to conclude that prices will move toward CONE.

As a comparison, PJM recently completed their capacity auction for the 2015/2016 planning year. Although PJM’s capacity prices have historically been significantly higher than that of MISO’s, the results might still be useful for comparison:

- PJM Annual Resource Price: $136.00 per MW-day ($49,640 per MW-year)
- PJM MAAC area Resource Price: $167.46 per MW-day ($61,123 per MW-year)
- PJM ATSI area Resource Price: $357.00 per MW-day ($130,305 per MW-year)

13. **Recommendations**

Work closely with your JAA or power supplier to make sure your interests are protected in the market, keep an eye on risks, look for opportunities to exploit, etc. Interested utilities and their JAA’s would do well to consider strategically located, jointly owned generation.

If there is one no-risk strategy that the Taskforce can whole-heartedly recommend, it is for utilities to take those cost-effective measures that can reduce peak demand for electricity. IAMU has just completed an analysis of several peak load reduction strategies for the City of Breda. The lessons learned, both in terms of modeling and results, will be useful for many IAMU members. IAMU and a growing number of members also have experience with a range of other demand response strategies and technologies, including smart grid applications and time-of-use pricing.

- **Reduce peak demand; improve load factor.** There are peak demand reduction strategies that can be implemented at less than the likely auction clearing price and at a small fraction of the cost of adding generating capacity
- Look for opportunities to own part of a diverse mix of strategically located generation
- Look for opportunities to invest in transmission
- Look for opportunities to own delivery infrastructure that you are now renting, i.e., substations and radial sub-transmission lines. Alternatively, use leverage to get the owner to accept a pre-payment arrangement.
- Educate customers; make them part of the solution
- Evaluate behind the meter generating technologies, including customer-owned resources
- Ensure that the utility’s/city’s own use of energy is efficient. Reduce distribution losses, evaluate city/utility infrastructure for cost effective energy efficiency investments.
Peak Demand Drives Costs
Rough Evaluation of Costs and Benefits of Air Conditioning Load Management

LOAD CONTROL COSTS: The following costs are from the IAMU 2 Degrees 2 SAVE program, except that no grant support is assumed. Other load control technologies and strategies are available, such as installation of behind the meter generation, control of city/utility loads (including motors/pumps in water and wastewater treatment), and time of use and interruptible rates. This example is intended to demonstrate an approach for a rough evaluation of the costs and benefits of air conditioning load control.

Cost of avoiding a kW of demand using controllable thermostats over 15 years = $18/year
Cost of avoiding a kW of demand using air conditioning switches over 15 years = $15/year

DEMAND-RELATED COSTS TO BE AVOIDED BY LOAD CONTROL: At least two and, in some cases three, major power supply costs are determined by a utility’s peak demand or coincident peak demand.

1. CAPACITY: The MISO auction clearing price (held in June, beginning 2013) is a reasonable proxy for the cost of capacity. Based on offers in the current monthly auction, it could be as low as $24/kW-year ($2/kW-month). On the other hand, debt plus O&M for a simple-cycle gas turbine could run $80/ kW-year.
   - Low auction clearing price = $24,000/MW-yr. = ($24/kW-yr.)
   - Lowest zone auction clearing price in PJM = $61,123/MW-yr.
   - Mid-range auction clearing price = $61,000/MW-yr. ($61/kW-yr.)
   - Cost of New Entry (CONE) = $98,000/MW-yr. ($98/kW-yr.)
   - Highest PJM auction clearing price (ATSI constrained zone) = $130,305/MW-yr. ($130/kW-yr.)

2. TRANSMISSION: Transmission charges vary depending on what facilities are used. In MISO, the charge is based on the coincident demand for the month. When evaluating air conditioning load control, a monthly peak kW can only be avoided during the four summer months when there is AC load, so the annual avoided cost is the monthly charge times four. Current transmission rates (below) will increase dramatically when the cost of multi-value projects and others are added to the MISO network rate:
   - ITC Midwest = $7.03/kW-mo. (monthly peak) x 4 summer months w/ AC control = $28.12/kW-yr.
   - Cornbelt/WAPA = $5.27/kW-mo. (12 mo. ratchet) = $63.24/kW-yr.
   - MEC = $1.62 (monthly peak) x 4 summer months with AC control = $6.48/kW-yr.
   - ATC (Wisconsin) = $4.17/kW-mo. x 4 = $16.68

3. DIRECTLY ASSIGNED FACILITY CHARGES: Many IAMU members rent radial lines and substations, referred to as directly assigned facilities (DAF). The charges vary widely, depending on facilities rented and utility load ratio share of use. Among IAMU members, DAF charges can be more than $50 per kW year.

EXAMPLE: The following is a comparison between the annual cost of a kW of peak demand for utility in the Alliant control area ($7.03 x 4 summer months), with demand at $5/kW-month and DAF charges of $2 per month:

<table>
<thead>
<tr>
<th>Capacity $60/kW-yr.</th>
<th>Transmission $28/kW-yr.</th>
<th>DAF $24/kW-yr.</th>
<th>Cost of Peak kW = $112/yr.</th>
</tr>
</thead>
<tbody>
<tr>
<td>VS.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Annual cost over 15 years to avoid a kW of peak demand using A.C. switches = $112/yr.

In this simple comparison, both the cost of a kW or peak demand and the cost of avoiding it are fixed over the 15 years. Trending the cost of capacity and transmission would show an even greater benefit for load control. Still another benefit is in avoiding fractional capacity credits, which are sold in 100 kW increments. IAMU is preparing a comprehensive list of strategies for reducing peak demand.
Part 2. Reciprocating Internal Compression Engines (RICE)

14. RICE and the MISO Market

Uncertainty about changes to EPA’s RICE rule is one reason the Taskforce report should be deemed preliminary. A meeting with the MISO capacity market staff is scheduled following adjournment of the annual conference (10-5-12). Here are some questions and answers members should consider. At the time of this writing, all of them need some level of clarification.

- How do the market design and price forecast affect a utility’s decision to modify or replace RICE units? If the proposed amendments to the NESHAP RICE rule are adopted, the additional operating hours are sufficient to make RICE units eligible to meet capacity requirements of the market (1st five summer emergence events for minimum of 4 hours each or 20 hours). This is true whether the engines are designated as being “in front of the meter,” as the RPGI engines are designated, or “behind the meter,” as all or most of the other engines are designated. A behind the meter generator is designated as a load modifying resource. An engine/generator that is in front of the meter may fall under the must-offer requirement in the Day ahead energy market.

- While adoption of EPA’s proposed amendments to the RICE rule would ensure that RICE units satisfy capacity requirements of the market, the question of whether a RICE resource receives a capacity credit – in the traditional sense – depends on the power supplier.

- There may be a market for excess RICE capacity among IAMU members, i.e., it might make sense for a utility with excess diesel capacity (or capacity that a JAA or power supplier does not value) to make the capacity available to other utilities at a fixed price. However, the resource apparently would have to be deliverable over network or point-to-point transmission. [Additional clarification may be needed on these arrangements.]

15. RICE TIMELINE AND OTHER CONSIDERATIONS

Diesel electric generators must be compliant with EPA’s NESHAP RICE rule by May 23, 2013 or run only for emergencies (ice storms, etc.). Proposed amendments provide up to 100 hours of operating time, including 50 hours for peak shaving (1st two years). A decision on proposed amendments to the rule is expected December 23, 2012, but may not be available in written form until March.

Recommendations:

- Check with power supplier/JAA to determine if your RICE capacity is needed and if credits will be available to utility.

- Consider filing by 1-15-12 for one-year extension, even if you ultimately decide not to proceed with retrofit. IAMU and others asked for blanket extension in our comments on the final rule. IAMUA has also asked if a joint filing could be made for a one year extension, but
we have been told that the rule does not permit that. IAMU has information about what is required for the filing.

- Before replacing RICE units, consider higher value of alternatives, i.e., larger, more fuel efficient, strategically located generation or much less costly demand response strategies.

### Extension for Installing Controls on RICE Engines

Per General Provisions (subpart A) of 40 CFR part 63, a request for a one-year extension of the compliance date for the purpose of installing controls as outlined in 40 CFR 63.6(i)(4)(i)(A) must be submitted by the owner or operator of the engine. Each engine for which an extension is being requested must be identified, along with the information specified in 40 CFR 63.6(i)(6). Requests for engines located in Iowa should be submitted to EPA Region 7.

63.6(i)(4)(i)(A): The **owner or operator of an existing source who is unable to comply with a relevant standard established under this part pursuant to section 112(d) of the Act may request that the Administrator (or a State, when the State has an approved part 70 permit program and the source is required to obtain a part 70 permit under that program, or a State, when the State has been delegated the authority to implement and enforce the emission standard for that source) grant an extension allowing the source up to 1 additional year to comply with the standard, if such additional period is necessary for the installation of controls.}
Part 3. Other Topics on the Taskforce Agenda

There are other topics on the Taskforce agenda that have been pushed aside as we focused on developments in MISO and on the related issue of the NESHAP RICE rule and whether utilities should retrofit or replace non-compliant engines. Whether these topics become the subject of a future Taskforce report is yet to be determined, but you can be sure that they will be covered at future conferences and workshops. Here are a few of those other topics that merit the attention of IAMU members:

A. Rates. Electricity rates are on the rise and apparently increases are coming at a pace that exceeds the rate of inflation. Among the reasons are: higher commodity-driven capital costs for new and replacement generators, huge investments in transmission, rising fuel and fuel delivery costs, and regulations addressing environmental and health costs. For many IAMU members, rate structures have not kept up with these changes. Utilities need to evaluate their rates, with close attention to eliminating or justifying declining blocks and rolling purchased power adders into base rates, especially when the adjustment have grown to exceed the base rate.

IAMU is developing educational materials for policymakers and customers built around the “unbundled” utility bill – one that distinguishes the cost of operating the distribution system (typically 8 to 20 percent of the rate), from power supply and other costs. These tools can be helpful in focusing customer attention on COST, where there are great opportunities for cutting, and away from rates.

B. Trends and Game Changers, include technologies we need to watch closely:

1) Technologies to Watch. Smart grid technology, including interval meters and home area networks will make it possible to have a far more efficient grid. At the customer end of the smart grid, these technologies will allow for time of use rates and a variety of load control options. It is hard to see an energy future that does not recognize the link between the cost of energy and the time it is used. These technologies will also provide information to customers in ways that will empower them to reduce their energy costs.

Other elements of a smart grid will make it possible to dynamically alter voltage and to integrate distributed generation, including customer-owned renewables.

2) Generation. In the absence of a comprehensive national energy policy, including a clearer understanding of how the industry will be expected to respond to climate change, picking a winning generation is a difficult task. Will it be gas, nuclear, solar, wind, biomass or some fuel or technology that is yet to be developed? Where to build it may be a easier question, but should it be in front or behind the meter? Should it be built locally or strategically sited to reduce congestion? Who should build it; utilities, independent power producers, joint action agencies, customers, or government? Should it be all of the above? These questions deserve our attention. The answers may benefit from greater dialogue between municipal utilities, their joint action agencies, and other stakeholders.
New technologies and improved old ones also need to be watched. For example, the cost of solar PV has come down dramatically in the last few years. For at least a few IAMU members, behind the meter PV appears to be a cost-effective alternative, if the capacity value is considered. An Iowa utility could expect to have about 70 percent of the nameplate capacity of a solar array available during a peak demand that occurred at ~ 3 p.m.

3) Electrification of Transportation. Automobile manufacturers, spurred by new mileage standards, are rolling out more electric, electric hybrid, and compressed natural gas vehicles. Wider use of either fuel will impact the future cost of electricity. But incentives, disincentives, regulations, or some combination will be necessary to ensure that batteries are not charged at the time of a utility peak demand.

C. Finding/keeping Qualified Personnel. The departure of a generation of baby boomers may make the job of finding and retaining qualified personnel a much harder task. This is likely to be an especially difficult job for very small utilities. Smaller municipal utilities are often the farm clubs for larger and it doesn’t help that the wages and salaries of municipal utilities personnel are often not competitive with the coops and investor-owned utilities. Besides paying competitive wages, municipal utilities would do well to consider joint action to share managers and other key personnel. Hiring locally and providing good training is another consideration. About half of the population lives within 50 miles of their birthplace. IAMU’s Professional Utility Leadership Link (PULL) program is also up and running and may be just what’s needed to bring an experienced hand to a temporary or part time position or to manage a special project.

D. Public power business model. For well over a century, municipal electric utilities have demonstrated the value of local control and community ownership. Where economies of scale have been needed, municipal utilities have joined together to build new generation, invest in transmission, and to deal with complex regulations. Current challenges, such as the MISO energy and capacity markets, staffing, credit and capital risks, and increased pressure for transfers to city general funds are not unique. The strengths of the business model are still there, as are the solutions. What we need to do is to capitalize on those strengths and keep them in front of our communities. Municipal electric systems would do well to regularly evaluate the extent to which they are keeping the public in public power and keeping community first.

The Taskforce has looked back at the 2002 publication by APPA entitled “It’s Your Future – Lead It” a Report of the APPA Task Force on Public Power in the 21st Century. The report makes 10 recommendations that offer sound approaches to policy direction and management that should be beneficial regardless of the future direction of the electric industry. Those recommendations have held up well in the decade since their publication. The report is available at www.appanet.org. Search for Public Power in the 21st Century.
### Appendix 1 – RAR

Some acronyms used in this table are: Load Serving Entity (LSE); Electric Distribution Companies (EDC); Zonal Resource Credit (ZRC); Planning Resource Auction (PRA); Independent Market Monitor (IMM).

<table>
<thead>
<tr>
<th>Month</th>
<th>Day</th>
<th>Process</th>
<th>2013-14 PY</th>
<th>Responsible entity</th>
</tr>
</thead>
<tbody>
<tr>
<td>September</td>
<td>1st</td>
<td>Annual Cost of New Entry and Net Cost of New Entry filing due to FERC</td>
<td>09/01/12</td>
<td>MISO</td>
</tr>
<tr>
<td>October</td>
<td>31st</td>
<td>Generation Verification Test Capacity/Generator Availability Data due</td>
<td>10/31/12</td>
<td>Resource Owner</td>
</tr>
<tr>
<td>November</td>
<td>1st</td>
<td>Coincident Peak Demand forecast by LSE/EDC due</td>
<td>11/01/12</td>
<td>LSE, EDC</td>
</tr>
<tr>
<td>November</td>
<td>1st</td>
<td>Loss of Load Expectation study results published by MISO (Publish PRM, Develop LRZs, Determine CIL and CEL, Establish LRR)</td>
<td>11/01/12</td>
<td>MISO</td>
</tr>
<tr>
<td>November</td>
<td>1st</td>
<td>Evidence for new GMA/Zonal Deliverability Charge hedges due</td>
<td>11/01/12</td>
<td>LSE</td>
</tr>
<tr>
<td>December</td>
<td>1st</td>
<td>Unforced Capacity values are published by MISO</td>
<td>12/01/12</td>
<td>MISO</td>
</tr>
<tr>
<td>December</td>
<td>15th</td>
<td>Peak Load Contribution submissions by EDC due</td>
<td>12/15/12</td>
<td>EDC</td>
</tr>
<tr>
<td>January</td>
<td>1st Bus. day</td>
<td>Transmission losses by Local Balancing Authority are posted by MISO</td>
<td>01/02/13</td>
<td>MISO</td>
</tr>
<tr>
<td>February</td>
<td>1st</td>
<td>Loss of Load Expectation study begins for next Planning Year</td>
<td>02/01/13</td>
<td>MISO</td>
</tr>
<tr>
<td>February</td>
<td>1st</td>
<td>Existing Load Modifying Resource/Energy Efficiency/External Resource registrations due for prompt Planning Year</td>
<td>02/01/13</td>
<td>LMR Owner</td>
</tr>
<tr>
<td>February</td>
<td>16th</td>
<td>Data for facility ZRC reference levels due 45 days prior to the close of the PRA</td>
<td>02/16/13</td>
<td>MP</td>
</tr>
<tr>
<td>March</td>
<td>1st</td>
<td>Post initial ZRC reference levels 30 days prior to the close of the PRA</td>
<td>03/01/13</td>
<td>IMM*</td>
</tr>
<tr>
<td>March</td>
<td>1st</td>
<td>New Load Modifying Resource/Energy Efficiency Resource/External Registrations due for prompt</td>
<td>03/01/13</td>
<td>LMR Owner</td>
</tr>
<tr>
<td>Month</td>
<td>Day</td>
<td>Event</td>
<td>Date</td>
<td>Responsible Party</td>
</tr>
<tr>
<td>-----------</td>
<td>--------</td>
<td>----------------------------------------------------------------------</td>
<td>----------</td>
<td>-------------------</td>
</tr>
<tr>
<td>March</td>
<td>1st</td>
<td>Generator Verification Test Capacity/Generator Availability Data for new resources or resources with increased capacity prompt Planning Year</td>
<td>03/01/13</td>
<td>LMR Owner</td>
</tr>
<tr>
<td>March</td>
<td>1st</td>
<td>MISO to complete its Coincident Peak Demand forecast review process</td>
<td>03/01/13</td>
<td>MISO</td>
</tr>
<tr>
<td>March</td>
<td>1st</td>
<td>Grandmother Agreement and Zonal Deliverability Charge hedge information posted by MISO</td>
<td>03/01/13</td>
<td>MISO</td>
</tr>
<tr>
<td>March</td>
<td>7th Bus. day</td>
<td>Fixed Resource Adequacy Plan due by LSE</td>
<td>03/11/13</td>
<td>LSE</td>
</tr>
<tr>
<td>March</td>
<td>15th</td>
<td>Fixed Resource Adequacy Plan review completed by MISO (The LSE will have until the PRA offer window opens to remedy any deficiencies in their FRAP.).</td>
<td>03/15/13</td>
<td>MISO(LSE)</td>
</tr>
<tr>
<td>March</td>
<td>25th</td>
<td>Provide facility specific 5 days prior to the close of the Auction</td>
<td>03/25/13</td>
<td>IMM</td>
</tr>
<tr>
<td>March</td>
<td>Last 3 Bus. days</td>
<td>Planning Resource Auction offer window is opened</td>
<td>03/27/13</td>
<td>MISO</td>
</tr>
<tr>
<td>April</td>
<td>1st 5 Bus. Days</td>
<td>Iterations of auction runs with the adjusted CILs and CELs may be required to ensure that a network loading is not violated. Additionally, MISO will work with the IMM to evaluate potential withholding.</td>
<td>04/01/13</td>
<td>MISO/IMM*</td>
</tr>
<tr>
<td>April</td>
<td>5th Bus. day</td>
<td>Planning Resource Auction results posted</td>
<td>04/05/13</td>
<td>MISO</td>
</tr>
<tr>
<td>April</td>
<td>6th Bus. Day</td>
<td>Assess the Capacity Deficiency Charge</td>
<td>04/08/13</td>
<td>MISO</td>
</tr>
<tr>
<td>April</td>
<td>11th Bus. day</td>
<td>MISO sends out the Capacity Deficiency Charge</td>
<td>04/15/13</td>
<td>MISO</td>
</tr>
<tr>
<td>April</td>
<td>11th Bus. days + 7</td>
<td>Capacity Deficiency Charge payment due</td>
<td>04/22/13</td>
<td>MISO</td>
</tr>
<tr>
<td>April</td>
<td>11th Bus. days + 7 + 2 Bus. days</td>
<td>Capacity Deficiency Charge payments made to MPs</td>
<td>04/24/13</td>
<td>MISO</td>
</tr>
<tr>
<td>June</td>
<td>1st</td>
<td>Planning Year starts</td>
<td>06/01/13</td>
<td>All</td>
</tr>
<tr>
<td>June</td>
<td>1st</td>
<td>Daily settlements starts</td>
<td>06/01/13</td>
<td>All</td>
</tr>
</tbody>
</table>
Note: The MISO website www.midwestiso.org has a library with many instructional presentations on Resource Adequacy Requirements.